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(54) **SYSTEM AND PROCESS FOR FLUE GAS
PROCESSING**

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(57) **ABSTRACT**

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The present invention is directed to a new and improved method for sequestration of carbon dioxide, the method including the steps of injecting a carbon dioxide-containing injection gas into a subsurface containment region with a series of captures zones; providing sufficient time for said injection gas to at least partially stratify and form constituent gas mixtures which at least partially accumulate in the capture zones; providing a vent associated with one of the capture zones; and, evacuating at least a portion of the constituent mixtures through the associated vent.

SYSTEM AND PROCESS FOR FLUE GAS PROCESSING

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority under 35 U.S.C. 119(e) and 37 C.F.R. 1.78(a)(4) based upon copending U.S. Provisional Application, Ser. No. 61/304,580 for SYSTEM AND PROCESS FOR FLUE GAS PROCESSING, filed Feb. 15, 2010, the disclosure of which is incorporated herein by reference.

FIELD OF THE INVENTION

[0002] The present invention relates to a system and process for flue gas processing, more specifically to a system and process for processing and sequestration of flue gas constituents in subsurface structures. The present invention also relates to a system for using the gas processing to enhance hydrocarbon recovery from low pressure subsurface geological formations.

BACKGROUND OF THE INVENTION

[0003] Increasing concentrations of greenhouse gases, including carbon dioxide, in the atmosphere are a subject of concern. It is feared that emission of these gases into the atmosphere could lead to global warming, sea-level changes, and different weather patterns, among other detrimental effects. Controlling the release of these gases into the atmosphere is thus an increasingly important concern. Response to this concern has led to governmentally limited prohibitions and restrictions on carbon dioxide emissions, or fees associated with the emissions of such gases. Those approaches lead to high economic costs for industries that emit green house gases, especially those that emit flue gases into the atmosphere.

[0004] In order to meet past and new emissions standards, several approaches have been developed to make flue gases cleaner. Some approaches to reduce the emissions of undesired particulates within various gases include using above ground technologies such as adsorption by micro porous solids and absorption by chemical solvents. Other approaches include the geosequestration of purified gas in underground formations. However, current technologies have not developed systems or processes that make large scale sequestration of CO₂ financially feasible.

[0005] Rather than sequestering the CO₂, which currently is not financially feasible for most large-scale operations, some methods utilize it in purified form to enhance oil recovery from underground formations. However, using purified CO₂ for this purpose also presents a number of problems for the producer of the well. In most large-scale enhanced oil recovery operations utilizing purified CO₂, the primary cost of the recovery is the purchase of CO₂, which may represent operating costs as much as 68% of the total cost of the revenue from the project. The cost of acquiring purified CO₂ in large quantities is driven by the very high cost of separation of CO₂ from flue gases and its subsequent transportation to the sequestration site where it can then be injected into the subsurface formation. Moreover, the relative cost of large scale CO₂ capture, injection, and sequestration increases as oil prices decline.

[0006] Traditional configurations for hydrocarbon recovery processes require subterranean depths of greater than

eight hundred meters, with a sufficient trapping mechanism and sufficiently porous geological texture to handle large volumes of injected gases. Different trapping mechanisms occur which vary depending on the associated structure and desired duration of the sequestration. In addition, traditional configurations require subsurface containment regions capable of receiving high flow injection rates under very high injection pressures to sustain CO₂ sequestration. Using the present invention, CO₂ sequestration is achievable at relatively shallower levels with reduced injection flow rates and pressures.

[0007] Despite the prior art's predominant usage of purified CO₂ in enhanced recovery methods, it is also possible to enhance the oil recovery process by using gases of differing compositions, such as those with compositions similar to common flue gases. Constituents of these mixtures may be at least partially soluble in hydrocarbons contained in the underground formation and in many situations the resulting solutions will experience a more favorable mobility due to decreased viscosity. In addition, the resulting low-cost pressurization of the underground containment region may promote increased recovery.

[0008] Moreover, potential sequestration locations for CO₂ injection are seldom located in close proximity to coal-fired electric power plants and other large scale flue gas sources. The cost of transporting purified liquid CO₂ by truck or pipeline is considerable. This circumstance exists for nonsequestration commercial markets of CO₂ as well. Therefore, the significant costs of carbon capture include the additionally significant costs of transporting liquefied CO₂ by tanker truck or pipeline. The combination of such energy costs and limited commercial demand for CO₂ do not make the sale of CO₂ captured by above-ground mechanical technologies commercially viable in many situations. For these reasons, neither sequestration nor the commercial sale of purified CO₂ are generally considered sufficient, practical, or financially feasible for utilizing all of the CO₂ contained in flue gases.

[0009] Additionally, the capital costs of the equipment necessary for large-scale separation and capture of CO₂ from power plant flue gases are enormous, generally in excess of \$1.2 billion per plant.

[0010] Furthermore, the cost of large-scale separation and capture of CO₂ from flue gases has generally been considered commercially prohibitive for waste disposal due to the enormous volumes of energy required to condense the gases to the point where liquid CO₂ can be extracted. For a coal-fired electric power plant, estimates are that the energy cost of CO₂ separation can exceed by 30% to 40% the electricity production capacity of the plant. The result of combined capital and energy cost of large-scale CO₂ separation and capture from power plant flue gases could be very substantial increases in the price of electricity to consumers. Some estimates are that costs to consumers would need to double for the method of disposal to become commercial viability.

[0011] Some prior attempts at utilizing hydrocarbon recovery techniques have been described in Screening and Ranking of Hydrocarbon Reservoirs for CO₂ Storage in the Alberta Basin, Canada by Buchu, which is incorporated by reference.

[0012] Heretofore, there exists a need for an improved system and process for hydrocarbon recovery using emission gases sequestered in geological strata.

SUMMARY OF THE INVENTION

[0013] The present invention is directed to a method for sequestration of carbon dioxide, said method comprising the

steps of injecting a carbon dioxide-containing injection gas into a subsurface containment region, said containment region further comprising a series of captures zones; providing sufficient time for said injection gas to at least partially stratify forming constituent gas mixtures and for said constituent mixtures to at least partially accumulate in said capture zones; providing a vent associated with one of said capture zones; and, evacuating at least a portion of one of said constituent mixtures through said vent.

DETAILED DESCRIPTION OF THE INVENTION

[0014] As required, detailed embodiments of the present invention are disclosed herein; however, it is to be understood that the disclosed embodiments are merely exemplary of the invention, which may be embodied in various forms. Therefore, specific structural and functional details disclosed herein are not to be interpreted as limiting, but merely as a representative basis for teaching one skilled in the art to variously employ the present invention in virtually any appropriately detailed structure.

[0015] An exemplary embodiment of the system and process for production of hydrocarbon using the sequestration of carbon dioxide is comprised of a flue gas source, a subsurface containment region, which may include a brine zone, an oil zone, and plural capture zones. The subsurface containment region is in communication with a compression source spaced apart from the subsurface containment region. Additionally, the subsurface containment region includes a vessel, a formation, or other structure which surrounds its perimeter. As illustrated, the flue gases are injected into the subsurface containment region from the compression source and are dispersed throughout. Flue gases associated with a brine zone would permeate through the brine material separating some of the constituent gases from the flue gas into soluble CO₂ and other insoluble gases. As these constituent gases are separated, they are allowed to migrate. Exemplary processes include the migration of at least a portion of the insoluble gases into a hydrocarbon fluid reservoir, where the additional soluble CO₂ permeates the fluid hydrocarbons, enhancing the transport characteristics of the hydrocarbon and thereby enhancing the hydrocarbon production. In other processes, the insoluble CO₂ is allowed to migrate to structurally higher areas of the subsurface containment region. Any CO₂ retained in the hydrocarbon zone may be extracted through hydrocarbon production, captured at the surface, and reinjected into the subsurface containment region for use in various embodiments of this invention.

[0016] Flue gases from various industrial processes may be utilized in the present invention and may be processed prior to introduction into the subsurface containment region. Alternatively, the present invention may remove some contaminants from the flue gas through a filtering or separation processes. Typically, the industrial flue gas may be processed during or in association with the industrial process by strippers or scrubbers.

[0017] In one embodiment, the flue gas 14 is processed to remove at least a portion of (1) undesirable particles, (2) sulfur dioxide, (3) nitrous oxides and (4) moisture content. The resulting flue gas may have a composition that is, for example, 10.73% CO₂, 1.39% CO, 0.76% NO_x, 0.03% SO₂, and 87.09% air, although percentages of constituent gases may vary. The greater the concentration of CO₂, the more desirable the flue gas is for application of this invention. Carbon Capture And Storage (CCS) in Nigeria: Fundamental

Science and Potential Implementation Risks, Galadima & Garba (2008 SWJ Vol 3, No. 2): pgs 95-99; and The Future of Carbon Capture and Storage (CCS) in Nigeria, Anastassia et al., (2009 SWJ Vol. 4, No. 3):1-6 which are attached hereto and incorporated by reference.

[0018] The composition and proportions of the flue gas and its contaminants may vary depending on the specific industrial process utilized. If solvent absorption of carbon dioxide is used for the sequestration, and monoethanolamine is the solvent, reactions with diatomic oxygen, nitrous oxides, and sulfoxides may lead to numerous operational problems such as foaming, fouling, increased viscosity, and formation of undesirable salts. Diatomic oxygen concentrations in the range of about 3% to 12% in typical flue gas streams are known to induce oxidative degradation of alkanolamines, resulting in severe corrosion of associated piping. Thus the proportion of oxygen should be minimized or oxygen inhibitors employed. Additional information on contaminants and flue gas processing is disclosed in Supap, T.; Idem, R.; Tontiwachwuthikul, P.; Saiwan, C. Analysis of monoethanolamine and its oxidative degradation products during CO₂ absorption from flue gases: A comparative study of GC-MS, HPLC-RID, and CE-DAD analytical techniques and possible optimum combinations. Industrial & Engineering Chemistry Research, 2006, 45 (8), 2437 which is incorporated by reference.

[0019] While the invention discloses using flue gas, other CO₂ containing gases may be utilized in the present invention. While pressurization of subterranean formations may be generally understood, by using a CO₂ enriched gas, unexpected benefits may be achieved through the enhanced liquidity of the fluid hydrocarbon as well as a reduction in the pressures necessary to achieve hydrocarbon recovery.

[0020] In one embodiment, the flue gases may be injected into the subsurface containment region through a compression source such as an injection well extending from the surrounding structure opposite the subsurface containment region into the subsurface containment region. See for example American Petroleum Institute, 2007, Background Report, "Summary of Carbon Dioxide Enhanced Oil Recovery (CO₂ EOR) Injection Well e Technology", 1220 L Street NW, Washington, DC, attached hereto and incorporated by reference. In addition, various textured surfaces may enhance the capacity of the subsurface containment region as well as allowing for an increase in the efficiency of the sequestration and hydrocarbon recovery. Some exemplary subsurface containment regions may include depleted oil and gas reservoirs, saline aquifers, coal beds and artificial vessels designed to sustain the hydrocarbon production. The injection well, which may be in communication with a production well, would inject the flue gases into the subsurface containment region. As the flue gases enter the subsurface containment region, through the process described above, the flue gas would separate for immersion of the fluid hydrocarbon by the separated soluble CO₂. Optionally, the subsurface containment region may be sealed from the ambient surface environment allowing for additional separation of the CO₂ from the flue gas and for additional saturation of the fluid hydrocarbon by soluble portions of the separated CO₂.

[0021] The flue gas when initially injected into the subsurface containment region is a mixture of constituent gases. Subsequent to the injection, the flue gas stratifies, at least partially, into zones of concentration of individual constituent gases dispersed throughout the subsurface containment region. Multiple molecular processes contribute to the strati-

fication. Additionally, the proportions of a constituent gas in a zone of concentration vary over time depending on the stratifying molecular process. The constituent gases have different relative densities, thus after being injected into the subsurface containment region, there is some tendency for the constituent gases to partially stratify over time. Because CO₂ is about 50% heavier than the average molecular weight of other constituent gases in air, those other constituent gases will tend to rise relative to the CO₂ resulting in at least two zones of concentration, with air concentrating above the CO₂. Because gaseous CO₂ is lighter than oil and water, insoluble CO₂ will tend to rise above those oil and water zones.

[0022] Other molecular processes that contribute to zones of concentration include but are not limited to adsorption. The adsorption properties of constituent gases in relationship to the within the subsurface containment region leads to zones of concentration. For example, if the subsurface containment region is an abandoned coal seam, affinity for adsorption of carbon dioxide over methane may be exploited to achieve a zone of concentration of carbon dioxide. This affinity may result in enhanced production of methane gas from the coal seam. If the subterranean structure has capillary structure, the different constituent gases of the flue gas travel through that capillary structure at different rates and thus zones of concentration may form. Further disclosure of apparatus and processes in separation of gases in this environment is in Effect of Heterogeneity in Capillary Pressure on Buoyancy Driven Flow of CO₂, Ehsan Saadatpoor, Steven L. Bryant, Kamy Sepehrnoori, available at http://www.cpge.utexas.edu/gcs/pubs/buoyancy_driven_flow_slides.pdf, which is incorporated by reference.

[0023] Upon stratification, a capture zone is associated with a given constituent gas. The constituent gas can then be directed for containment, reinjection, or elsewhere in the process. Gas vents, such as evacuation ducts, are associated with a desired capture zone in order to direct the contents of the capture zone to another desired location. In the case of a capture zone associated with carbon dioxide, the gas may be redirected to an injection well for resequestration into a non-capture zone such as a hydrocarbon zone to achieve incrementally enhanced hydrocarbon recovery. It may also be directed to a system for enhanced hydrocarbon recovery. The evacuation ducts are associated with capture zones and thus may be placed at varying depths or associated with any location where stratification may occur.

[0024] After a portion of the CO₂ is sequestered from the flue gas, it may diffuse through the pores of the subsurface containment regions or the associated brine and hydrocarbon zones. Saline structures may also present additional characteristics for containing the sequestered CO₂ or an impermeable capping material may be located between the injection well and the injected flue gases to seal the injected gases. The impermeable cap may include but is not limited to solid, liquid, or gaseous materials which limit undesired migration of sequestered CO₂.

[0025] In an alternative embodiment, surface compression may be utilized to inject the flue gas into the subsurface containment region passing at least one subsurface geological zones comprised of brine, hydrocarbons, a mixture of brine and hydrocarbons, air, soil, or artificial structures. Generally, "brine" consists of non-potable water and "hydrocarbons" consist of crude oil and/or natural gas. "Miscibility" is the ability of two or more substances to form a single homogeneous phase when mixed in certain proportions. For petro-

leum reservoirs, miscibility is the physical condition between two or more fluids that will permit them to mix in certain proportions without the existence of an interface. If two fluid phases form after some amount of one fluid is added to others, the fluids are considered "insoluble" under those conditions.

[0026] In order to enhance the oil recovery, the carbon dioxide is preferably soluble with the associated reservoir oil. The solubility of CO₂ and other injected gases depends upon factors such as reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition. The enhanced recovery processes involve manipulating these conditions to achieve miscibility between the injected gas and the oil.

[0027] The oil reservoir pressure at the start of a conventional CO₂ flood should be at least 1.38 MPa above the minimum miscibility pressure (MMP) to achieve miscibility between CO₂ and reservoir oil. This means that the ratio between reservoir pressure and minimum miscible pressure normally should be >1. During the enhanced oil recovery (EOR) also referred to as the secondary stage of oil recovery, the typical subsurface containment region for EOR may have various degrees of suitability, depending on the intrinsic subsurface characteristics and the chemical composition of the oil mixture. The range of reservoir and fluid properties suitable for CO₂ miscible injection is quite wide; however, exemplary reservoirs should have oil API gravity >27° (light oils with density <900 kg/m³), oil saturation S_o >25%, reservoir pressure >7.6 MPa and ideally 1.4 MPa higher than the minimum miscible pressure (MMP) at the time of CO₂ injection. In addition, the containment barrier porosity should be greater than 15% with permeability >1 md. Immiscible CO₂ flooding is much less common; nevertheless it may be applied to heavy and medium oils (10-25° API; 900-1000 kg/m³ density) and in-situ viscosities of 100 to 1000 mPa/s (cp).

[0028] Some limited studies have shown that, under cyclic immiscible recovery conditions, gas injection mixtures containing from 10-25% CO₂ have achieved exceptional oil recovery. More discussion on enhanced oil recovery results in varying conditions is disclosed in Rivas, O., Embid, S., and Bolivar, F., 1994. Ranking reservoirs for carbon dioxide flooding processes. SPE Paper 23641, SPE Advanced Technology Series, v. 2 (Rivas et al., 1994), which is incorporated by reference.

[0029] In another alternative embodiment, the flue gas may be injected directly into an oil zone or a brine zone of the subsurface containment region, where at least some quantity of CO₂ from a capture zone is employed. Disclosure of sequestration of CO₂ is included in U.S. Pat. App. Nos. 20070215350 and 20100000737, which are incorporated by reference.

[0030] After sequestering the CO₂ from the flue gases, the sequestered gases may be further separated by the Brine Zone, physically, mechanically or chemically through a reaction process such as but not limited to forming carbonic acid, and then any remaining sequestered gases may be transported to the Oil Zone, where at least some additional quantity of CO₂ is extracted from the flue gas via a molecular process. The non-soluble gases may be separated from the Oil Zone and be transported for capture at Zones 1, 2 or 3 depending on the specific configuration and relative density of the separated gases.

[0031] Optionally, the extraction of quantities of CO₂ from the flue gas injected into the brine zone or oil zone may be further increased if the subsurface containment region is pres-

surized. The pressurization may be increased to a point approaching but not equaling the fracture gradient of the subsurface containment region in order to achieve pressures and temperatures of greater solubility of CO₂ with formation liquids and/or to increase the drive mechanism to enhance the recovery of hydrocarbons. "Fracture gradient," measured in pounds per square inch per feet depth, is the pressure that if applied to rock or similar object within a subsurface containment region, will cause that rock to physically fracture. The subsurface pressure of said subsurface containment region may be increased by one or more means such as mechanical compression at the surface of the injected flue gas, flooding the formation with water, and adding chemical agents to the flue gas and/or to the subsurface brine and/or hydrocarbon bearing zones. U.S. Pat. Nos. 6,491,053, 7,506,690, 7,341,102, 6,318,468 and 4,744,417 involve processes and apparatus for enhanced hydrocarbon recovery using CO₂ at varying pressures and is incorporated by reference.

[0032] In yet another embodiment, the non-soluble gases that filter through the brine zone or through the oil zone may be isolated from the ambient environment to allow the CO₂ and other gases to separate according to their relative densities. Because CO₂ is about 50% heavier than air, the air component of the flue gas will tend to rise relative to the CO₂ resulting in at least two zones of concentration, with air concentrating above the CO₂. Because CO₂ is lighter than oil and water, non-soluble CO₂ will tend to rest on top of those zones.

[0033] In yet another embodiment, the contents of a capture zone having a constituent gas other than CO₂ may be directed outside the subsurface containment region into the atmosphere under controlled conditions, making the evacuated capture zones available for receipt of additional gasses. In this embodiment, at least one vent associated with at least one of the capture zones and associated with at least one constituent gas is used to extract at least some of the constituent gas through the associated vent at the desired capture zone.

[0034] The nature of CO₂ leakage behavior will depend on properties of the subterranean structure, primarily its permeability, and on the thermodynamic and transport properties of CO₂ as well as other fluids with which it may interact in the subsurface. At typical temperature and pressure conditions in the shallow crust (depth <5 km), CO₂ is less dense than water, and therefore is buoyant in most subsurface environments. Upward migration of CO₂ will occur whenever appropriate vertical permeability is available. Potential pathways for CO₂ migration to structurally high areas of subsurface containment regions include (1) migration through porous rock, and (2) migration along faults or fractures. More disclosure on CO₂ migration is in Assessment of the CO₂ Sealing Efficiency of Pelitic Rocks: Two-Phase Flow and Diffusive Transport, paper 536, presented at 7th International Conference on Greenhouse Gas Control Technologies, Vancouver, Canada, Sep. 5-9, 2004; Zweigel, P., E. Lindeberg, A. Moen and D. Wessel-Berg. Towards a Methodology for Top Seal Efficacy Assessment for Underground CO₂ Storage, paper 234, presented at 7th International Conference on Greenhouse Gas Control Technologies, Vancouver, Canada, Sep. 5-9, 2004; Gibson-Poole, C. M., R. S. Root, S. C. Lang, J. E. Streit, A. L. Hennig, C. J. Otto and J. Underschultz; Conducting Comprehensive Analyses of Potential Sites for Geological CO₂ Storage, paper 321, presented at 7th International Conference on Greenhouse Gas Control Technologies, Vancouver, Canada, Sep. 5-9, 2004; Lindeberg, E. The Quality of a CO₂ Reposi-

tory: What is the Sufficient Retention Time of CO₂ Stored Underground?, in: J. Gale and Y. Kaya (eds.), Greenhouse Gas Control Technologies, Elsevier Science, Ltd., Amsterdam, The Netherlands, 2003; and Espie, T. Understanding Risk for the Long-Term Storage of CO₂ in Geologic Formations, paper 42, presented at 7th International Conference on Greenhouse Gas Control Technologies, Vancouver, Canada, Sep. 5-9, 2004, which are incorporated by reference.

[0035] In yet another embodiment, a portion of any CO₂ and other constituent gases not associated with capture zones is captured proximately in the upper portion of the subsurface containment region. The gas composition is optionally monitored to detect higher proportions of the flue gas constituent gases and pressure flows. The subsurface containment region may be provided with a mechanical body, such as a gas containment layer, disposed near its upper portion. Disclosure of monitoring and gas containment systems is in U.S. Pat. Nos. 7,448,828 and 5,063,519, which are incorporated by reference. The contents of the mechanical body are re-injected through secondary compression back into the subsurface containment region under miscible or immiscible conditions, repeating the injection process previously described as desired.

[0036] In yet another embodiment, the contents of a CO₂ associated capture zone are directly produced via conventional gas production means. In this embodiment, at least one vent associated with a CO₂ capture zone within the subsurface containment region is used to direct at least some of the constituent gas through the associated vent. In a further embodiment, the constituent gas directed from a CO₂ associated capture zone is re-injected through secondary compression back into the subsurface geological formation under miscible or immiscible conditions using secondary compression. Optionally, the gas directed from the CO₂ associated capture zone is injected directly into an oil zone.

[0037] In yet another embodiment, the injected flue gas may be shut-in for a period of time to allow the injected gases to soak in the brine and/or hydrocarbon zones of the subsurface containment region. The injected flue gas may alternatively be shut-in for a period of time to allow the partial or complete stratification of flue gases, where the constituent gases stratify according to their relative densities. Each constituent gas is associated with a relative capture zone for release from the subsurface containment region.

[0038] In yet another embodiment, gaseous CO₂ from the flue gas not associated with a capture zone or not directed from a capture zone is stored in the subsurface containment region by sealing its surrounding surface using known techniques, such as a containment barrier around the perimeter of the subsurface containment region. The containment barrier is composed of material with low gas permeability. The barrier may be composed of existing natural material such as caliche, calcrete, silicrete. Alternatively, the containment barrier may be composed of manmade material. U.S. Pat. App. No. 20090220303 discloses using containment barriers in sequestration and is incorporated by reference.

[0039] While the foregoing detailed description has disclosed several embodiments of the invention, it is to be understood that the above description is illustrative only and not limiting of the disclosed invention. It will be appreciated that the discussed embodiments and other unmentioned embodiments may be within the scope of the invention.

Having thus described the invention, what is claimed as new and desired to be secured by Letters Patent is as follows:

1. A method for sequestration of carbon dioxide, said method including the steps of:

injecting a carbon dioxide-containing injection gas into a subsurface containment region having a series of captures zones;

providing sufficient time for said injection gas to at least partially stratify forming constituent gas mixtures and for said constituent mixtures to at least partially accumulate in said capture zones;

providing a vent associated with one of said capture zones; and,

evacuating at least a portion of one of said constituent mixtures through said vent.

2. The method of claim 1, wherein said injection gas is a flue gas.

3. The method of claim 1, further comprising a compression source for injecting said injection gas.

4. The method of claim 1, further comprising the step of pressurizing said containment region.

5. The method of claim 1, wherein said evacuated constituent mixture includes carbon dioxide, said method further including the step of reinjecting said evacuated constituent mixture into said containment region.

6. The method of claim 1, further comprising the step of enclosing said containment region with a sealing surrounding surface.

7. A method for enhanced recovery of hydrocarbons and sequestration of carbon dioxide, said method comprising the steps of:

injecting a carbon dioxide-containing injection gas into a subsurface containment region, said containment region further comprising a series of captures zones and being

associated with a hydrocarbon-bearing oil zone, whereby at least a portion of said injection gas contacts said oil zone;

providing sufficient time for said injection gas to at least partially stratify forming constituent gas mixtures and for said constituent mixtures to at least partially accumulate in said capture zones;

providing a vent associated with one of said capture zones; evacuating at least a portion of one of said constituent mixtures through said vent; and,

producing said hydrocarbons from said containment region.

8. The method of claim 7, wherein said injection gas is injected into said containment region under conditions of miscibility with at least a portion of said hydrocarbons.

9. The method of claim 7, further comprising the step of capturing carbon dioxide from said produced hydrocarbons.

10. The method of claim 9, further comprising the step of reinjecting said captured carbon dioxide into said containment region.

11. The method of claim 7, wherein said injection gas is a flue gas.

12. The method of claim 7, wherein said injection gas is injected using a compression source.

13. The method of claim 7, further comprising the step of pressurizing said containment region.

14. The method of claim 7, wherein said evacuated constituent mixture further comprises a proportion of carbon dioxide, and said method includes the step of reinjecting said constituent mixture into said containment region.

15. The method of claim 7, further comprising the step of providing a sealing surrounding surface enclosing said containment region.

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